RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three and nine months ended September 30, 2009 to the three and nine months ended September 30, 2008, respectively.

Revenues

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2009	2008	$ Change	% Change	2009	2008	$ Change	% Change
Transmission	296	315	(19)	(6)	869	912	(43)	(5)
Distribution	831	797	34	4	2,620	2,454	166	7
Other	17	14	3	21	48	37	11	30
	1,144	1,126	18	2	3,537	3,403	134	4
Average Ontario 60-minute peak demand *(MW)*[1]	21,374	23,156	(1,782)	(8)	21,058	22,072	(1,014)	(5)
Distribution - units distributed to customers *(TWh)*[1]	6.7	7.0	(0.3)	(4)	21.4	22.1	(0.7)	(3)

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were lower by $19 million, or 6%, in the third quarter, and by $43 million, or 5%, in the first nine months compared to the same periods last year. The average monthly peak demand was lower for both the quarter and the year-to-date period resulting in reductions in our transmission revenues of $16 million and $25 million, respectively.

Export service revenues attributable to the transmission of electricity to other jurisdictions were lower by $4 million in the quarter and by $12 million in the first nine months due to volume reductions combined with the impact of the May 28, 2009 Ontario Energy Board (OEB) decision. We also experienced higher other revenues of approximately $1 million in the quarter but lower revenues of approximately $1 million on a year-to-date basis which includes the impact of the May 28, 2009 OEB decision. Consistent with this decision, actual export service credit amounts and ancillary revenues in excess of forecast levels are to be recorded as regulatory liabilities.

Transmission revenues for the third quarter and in the first nine months were affected by two OEB-approved transmission tariff rate changes that occurred during the year which resulted in nominal changes for the quarter and decreased revenues of $5 million in the year-to-date period.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution rate. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $34 million, or 4%, in the third quarter, and by $166 million, or 7%, in the first nine months compared to the same periods last year. This change related primarily to the recovery of higher purchased power costs of $21 million in the third quarter and $126 million in the first nine months, as described below under "Purchased Power."

Distribution revenues increased by $34 million, or 4%, in the third quarter, and by $166 million, or 7%, in the first nine months compared to the same periods last year. This change related primarily to the recovery of higher purchased power costs of $21 million in the third quarter and $126 million in the first nine months, as described below under "Purchased Power."

The OEB's decision on smart meters and approved distribution tariff increases for our subsidiary, Hydro One Networks Inc. (Hydro One Networks), on December 18, 2008, in respect of our cost of service application, and on May 13, 2009, in respect of our rate application under the Third Generation Incentive Rate Mechanism resulted in higher distribution revenues of $18 million during the third quarter and $50 million in the first nine months compared to the same periods last year. These tariff rate increases, which support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, were implemented on February 1, 2009, and June 1, 2009 respectively.

Distribution revenue increases were partially offset by lower energy consumption, primarily resulting from milder weather this year which reduced our distribution revenues by $2 million in the quarter and $7 million in the first nine months. In addition, prior year revenues included amounts associated with the recovery of a distribution-related regulatory account that ceased effective March 31, 2008, resulting in lower revenues of $5 million on a year-to-date basis.

We also experienced lower ancillary revenues of approximately $3 million in the quarter but higher ancillary revenues of approximately $2 million in the year-to-date period.

Other

Our Telecom Business, which owns newly constructed dedicated optical network providing secure, high capacity connectivity in Ontario, contributed additional revenues of $3 million, or 21%, in the quarter and $11 million, or 30%, in the year-to-date period.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for low-volume and other designated customers are based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2007	1,000	750	5.0	5.9
May 1, 2008	600	750	5.0	5.9
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6

Purchased power costs increased in 2009 by $21 million, or 4%, to $547 million in the third quarter and increased by $126 million, or 8% to $1,731 in the first nine months compared to the same periods last year. The increase in our purchased power costs were primarily due to changes in the OEB's RPP rate for residential and other eligible customers of $28 million in the quarter and $121 million in the year-to-date period, the impact of higher charges levied by the IESO of $3 million in the quarter and $25 million in the first nine months, reflecting both higher transmission charges due to the OEB's August 28, 2008 and May 28, 2009 transmission rate decisions and increased wholesale market service charges, and higher purchased power costs for customers who are not eligible for the RPP of $6 million in the quarter and $12 million in the year-to-date period. These increases were partially offset by lower demand for electricity of $16 million for the quarter and $32 million for the year-to-date period.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.
Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2009	2008	$ Change	% Change	2009	2008	$ Change	% Change
Transmission	109	104	5	5	332	306	26	8
Distribution	144	139	5	4	418	392	26	7
Other	14	13	1	8	41	34	7	21
	267	256	11	4	791	732	59	8

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $5 million, or 5%, in the quarter and by $26 million, or 8%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $17 million in the quarter and $24 million on a year-to-date basis, compared to the same periods last year. These increases were primarily attributable to higher expenditures on our planned station maintenance programs, particularly on power equipment and transformers, higher requirements for unplanned corrective maintenance, engineering support and expanded forestry programs. In addition, we experienced a decrease of $12 million in the third quarter but an increase of $2 million in the first nine months related to expenditures incurred to support the transmission system. After consideration of a one-time settlement credit in 2008 associated with the transfer of assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario (FSCO), the year-over-year change in the first nine months to expenditures incurred to support the transmission system is effectively a decrease consistent with that experienced in the third quarter. These reductions are primarily attributable to the reallocation of resources in support of our larger capital work program.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $5 million, or 4%, in the quarter and by $26 million, or 6%, on a year-to-date basis, compared to the same periods last year. Higher expenditures within our work programs of $16 million in the quarter and $24 million for the first nine months resulted from higher expenditures on our unplanned line maintenance, corrective planned station maintenance, customer care and expanded forestry programs. We have expanded our forestry program to contribute to improved reliability. Our expenditures in support of our distribution business were lower by $11 million in the quarter and were higher by $2 million on a year-to-date basis. After consideration of a one-time settlement credit in 2008 associated with the transfer of assets to the Inergi pension plan following approval from the FSCO, the year-over-year change in the first nine months to expenditures incurred to support the distribution system is effectively a decrease consistent with that experienced in the third quarter. These reductions are attributable to the reallocation of resources in support of our larger capital work program partially offset by higher information technology support expenditures related to our entity-wide information system.

Depreciation and Amortization

Depreciation and amortization expense increased by $2 million, or 1%, to $139 million in the third quarter. The increase was due to higher depreciation expense from new assets placed in service, partially offset by the reduction to amortization expense of a regulatory account after completion of recovery. On a year-to-date basis, depreciation and amortization expense decreased by $7 million, or 2%, to $392 million primarily as a result of reduced amortization relating to fully recovered regulatory accounts, partially offset by higher depreciation expense from new assets placed in service.

Financing Charges

Financing charges increased by $6 million, or 8%, to $79 million in the third quarter and by $8 million, or 4%, to $225 million for the year-to-date compared to the same periods last year. The increases primarily resulted from higher net interest expense, reflecting higher average levels of debt and by lower investment income reflecting lower average investments and lower average short-term interest rates. These increases were partially offset by lower average long-term borrowing rates and

higher interest capitalization due to increased construction. On a year-to-date basis, financing charges were further impacted, in comparison to the prior year, by a one-time $6 million interest credit in the first quarter of 2008 related to the Inergi pension asset transfer.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $10 million, or 45%, to $12 million in the third quarter and decreased by $44 million, or 53%, to $39 million on a year-to-date basis compared to the same periods last year. The changes primarily reflect the impact of lower income before provision for payments in lieu of corporate income taxes and increased temporary differences relating to higher capital cost allowance deductions being available on our information system and smart meter investments, combined with temporary differences associated with certain regulatory accounts. These decreases were partially offset by the recognition of future income taxes and the corresponding regulatory impacts.

Net Income

Net income of $100 million in the third quarter and $359 million year-to-date was lower by $12 million, or 11% and $8 million, or 2% respectively, compared to 2008 results. In the quarterly and year-to-date periods, net income was affected by higher operation, maintenance and administration expenditures primarily related to work programs necessary to sustain our transmission and distribution systems. In addition, lower transmission revenues resulted from lower average monthly peak demands and lower export service revenues. These impacts were partially offset by the higher distribution tariff revenues associated with the December 18, 2008 and May 13, 2009 OEB rate decisions in support of necessary work programs which enable the safe and reliable delivery of electricity. In addition, payments in lieu of corporate income taxes were lower and reflect higher capital cost allowance deductions being available on our information system and smart meter investments.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2007 through September 30, 2009. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2009				2008			2007
Quarter ended	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**[2]	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**
Total revenue[1]	1,144	1,090	1,303	1,194	1,126	1,055	1,222	1,129
Net income[1]	100	82	177	131	112	98	157	90
Net income to common shareholder[1]	96	77	173	126	108	93	153	85

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	2009	2008	2009	2008
Operating activities	274	364	653	848
Financing activities				
Long-term debt issued	300	-	900	550
Long-term debt retired	-	-	(400)	(540)
Short-term notes payable	(165)	34	60	159
Dividends paid	(26)	(72)	(161)	(186)
Investing activities				
Capital expenditures	(400)	(321)	(1,119)	(835)
Other financing and investing activities	11	2	25	16
Net change in cash and cash equivalents	(6)	7	(42)	12

Operating Activities

Net cash from operating activities decreased by $90 million to $274 million in the third quarter and decreased by $195 million to $653 million in the first nine months, compared to 2008 results. These reductions are a result of higher working capital primarily related to increases in our work program requirements and to amounts recorded in certain regulatory accounts such as the regulatory liability refund account. These reductions were partially offset by the repayment to customers in 2008 of amounts recorded in the revenue difference deferral account following the 2007 transmission rate decision.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At September 30, 2009, we had $60 million of short-term notes outstanding. Our Commercial Paper Program is supported by a $1 billion committed revolving credit facility with a syndicate of banks maturing August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At September 30, 2009, we had $6,625 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On July 27, 2009, we filed a base shelf prospectus to renew our Medium-Term Note Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program is $3 billion, all of which currently remains available until August 2011.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $1 billion credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During the third quarter of 2009, we issued $300 million in long-term debt. There were no debt maturities. In the third quarter of 2008 there were no long-term debt issues or maturities. In the third quarter of 2009, the amount of short term notes outstanding decreased by $165 million compared to an increase of $34 million in the third quarter of 2008.

In the third quarter of 2009, we paid dividends to the Province of Ontario (the Province) in the amount of $26 million, consisting of $22 million in common dividends and $4 million in preferred dividends. In the comparative period for 2008, we paid common dividends of $68 million and preferred dividends of $4 million.

In the first nine months of 2009, we paid dividends to the Province in the amount of $161 million, consisting of $148 million in common dividends and $13 million in preferred dividends. In the comparative period last year, we paid common dividends of $173 million and preferred dividends of $13 million.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations and maintenance of the deemed regulatory capital structure. Common dividends pertaining to the quarterly financial results are generally declared and paid in the quarter immediately following.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2009	2008	$ Change	% Change	2009	2008	$ Change	% Change
Transmission	233	179	54	30	638	439	199	45
Distribution	166	139	27	19	477	387	90	23
Other	1	3	(2)	(67)	4	9	(5)	(56)
	400	321	79	25	1,119	835	284	34

Transmission

Transmission capital expenditures increased by $54 million, or 30%, to $233 million in the third quarter, and increased by $199 million, or 45%, to $638 million in the first nine months, compared to the same periods in 2008.

Expenditures to expand and reinforce our transmission system were $146 million in the quarter and $349 million for the first nine months of the year, representing increases of $71 million and $163 million over the respective comparable periods. These increases were primarily attributable to a number of significant inter-area network upgrade projects to increase generation as well as an increase in expenditures on local area supply projects to address growing loads. These increases were slightly offset by a number of load and generation projects that were completed or that were nearing completion last year, such as the Pleasant and Lambton transformer station projects. During 2008, we connected approximately 1,940 MWs of new generation to our transmission system.

Inter-area network upgrades with significant expenditures include the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the Greater Toronto Area (GTA), the South Western Ontario Capacitor Banks Project, which is linked to the Bruce to Milton project and which will expand transmission capacity in South Western Ontario and the High Voltage Shunt Capacitors Project which will improve reliability across our fleet of shunt capacitor bank installations. The impact of these increases are partially offset by the substantial completion in 2008 of an interconnection project with Québec that will increase access to emission-free hydroelectric power.

Local area supply projects with significant expenditures include our GTA West Transmission Reinforcement Project and our Woodstock Area Transmission Reinforcement Project both of which will increase capacity to ensure supply reliability in those areas, our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which will increase transmission capacity in the Western Brampton area to allow for future load growth and our Essa Transformer Station to Stayner Transformer Station connection, which was placed in service during the third quarter and has improved the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.
Expenditures to sustain our existing transmission system were $68 million in the quarter and $204 million on a year-to-date basis, representing a reduction of $4 million and an increase of $28 million compared to the same periods last year. Decreased expenditures in the quarter are mainly attributable to the completion of our Claireville Transformer Station Project which has improved reliability to meet growing demand. The year-over-year increase primarily relates to the refurbishment and replacement of end-of-life equipment associated with various station projects. We also incurred higher component replacement expenditures as a result of emergency restoration work on our lines.

Our other transmission capital expenditures were $19 million in the quarter and $85 million for the first nine months, representing a decrease of $13 million and an increase of $8 million respectively over the comparative periods. Decreased expenditures in the quarter are mainly attributable to higher project support expenditures recognized in the third quarter of last year. The year-over-year increase is mainly attributable to higher expenditures associated with information security enhancements, theft prevention programs and information technology project expenditures related to an entity-wide information system replacement and improvement project to replace end-of-life systems and improve productivity, the second phase of which was placed in service during the third quarter.

Distribution

Distribution capital expenditures increased by $27 million, or 19%, to $166 million in the third quarter and by $90 million, or 23%, to $477 million for the first nine months, compared to the same periods in 2008.

Capital expenditures to expand and reinforce our distribution network were $87 million in the quarter and $258 million for the first nine months of the year, representing increases of $19 million and $66 million over the comparable periods. These increases primarily reflect ongoing investments in our Smart Meter Program. During the quarter, we installed approximately 113,000 smart meters, bringing our cumulative program total to about 1,138,000 meters. We are also focused on the development and integration of the systems required for time-of-use billing, including integration to the IESO meter data repository.

Expenditures to sustain our distribution system of $64 million in the quarter and $173 million year-to-date, increased by $3 million and $17 million, respectively, compared to the same periods last year. These increases were primarily the result of increased engineering and construction work to upgrade or replace wholesale meters, increased investments to replace components within our distribution stations and higher expenditures on our planned and unplanned line work programs including planned replacement of end of life equipment, partially offset by lower costs related to line relocation work. Our other distribution capital expenditures were $15 million in the quarter and $46 million for the first nine months of the year, representing increases of $5 million and $7 million over the comparable periods. The majority of these expenditures reflect our investment in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures for 2009 are budgeted at $1.6 billion. The 2009 capital budgets for our transmission and distribution businesses are approximately $950 million and $650 million, respectively. Capital expenditures are expected to exceed $1.9 billion in 2010 and $2.1 billion in 2011, primarily reflecting initial investments required under the *Green Energy Act, 2009* (the Act), as well as those investments required to expand, refurbish or replace transmission and distribution infrastructure consistent with government policy, local area supply requirements and the preventive and corrective maintenance needs to manage aging assets that will facilitate an adequate and reliable supply of electricity in the public interest, as well as, enable renewable generation connections. These investments also reflect the continued mass deployment of smart meters that began in 2007 within our distribution businesses and which will be completed by the end of 2010, and the replacement of critical information technology systems. Capital expenditures of our other business segment are budgeted at about $7 million in 2009, reflecting sustainment of the fibre optic network.

Planned capital expenditures have increased from levels previously disclosed by approximately $200 million in 2010 and $600 million in 2011 primarily as a result of additional investments in the electricity system required to accommodate the anticipated increase in renewable energy generation associated with the Feed-in-Tariff Program, and higher investments through advanced technologies to increase functionality and reliability of the electricity grid under the Act. Investments in advanced technologies will enable a modern and flexible electricity grid and build on the investment already planned for and underway, in smart meters and the associated communications and data processing capacity. In conjunction with the Ontario Power Authority, we have identified specific transmission and distribution upgrades to enable renewable generation. The Government of Ontario requested our company to proceed with the planning, development and implementation of such upgrade projects and to provide opportunities for participation by potentially affected aboriginal peoples.

The actual timing of the projects and expenditures will have various dependencies including regulatory and government approvals such as Section 92 leaves-to-construct, environmental assessments and our distribution and transmission Green Energy Plans, as well as the timing of generator contributions for enabling facilities under recent amendments to the *Transmission System Code*. Accordingly, there is significant uncertainty regarding the extent and timing of these expenditures, however, future capital expenditures are expected to remain elevated beyond 2011.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

September 30, 2009 (Canadian dollars in millions)	Total	2009[1]	2010/2011	2012/2013	After 2013
Contractual Obligations *(due by year)*					
Short-term notes payable	60	60	-	-	-
Long-term debt – principal repayments	6,625	-	1,100	1,200	4,325
Long-term debt – interest payments	6,062	134	701	597	4,630
Inergi outsourcing agreement[2]	244	27	200	17	-
Operating lease commitments	60	2	13	13	32
Total Contractual Obligations	13,051	223	2,014	1,827	8,987
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	1,000	-	1,000	-	-
Letters of credit[4]	121	110	11	-	-
Guarantees[4]	325	325	-	-	-
Pension[5]	29	21	8	-	-
Total Other Commercial Commitments	1,475	456	1,019	-	-

[1] The amounts disclosed represent the balances due over the period October 1, 2009 to December 31, 2009.

[2] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term and have entered into discussions with Inergi that are expected to continue into early 2010 to determine the potential of exercising our option to extend the contract with Inergi.

[3] As a backstop to our commercial paper program, we have a $1,000 million revolving standby credit facility with a syndicate of banks which matures in August 2010.

[4] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $14 million included in letters of credit pertain to operating letters of credit and to surety bonds which comprise a letter of credit for $10 million issued in January 2009 relating to an agreement to purchase goods. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the Market Rules using guarantees of up to a maximum of $325 million and on behalf of a distributor using a guarantee of up to a maximum of $335 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2009 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2009 will be about $105 million. Contributions beyond 2009 will be based on an actuarial valuation effective no later than December 31, 2009 and will depend on future investment returns, changes in benefits and actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

During the first nine months of 2009, the deferred pension asset reported on our Balance Sheet decreased by $13 million to $428 million. We have contributed $84 million into our pension plan in 2009 and incurred $97 million in net periodic pension benefit costs. Our annual funding contributions for 2009 will be approximately $105 million. Contributions beyond 2009 will be based on a pending actuarial valuation effective no later than December 31, 2009 and will depend on future investment returns, changes in benefits and actuarial assumptions.

Performance of the pension plan has improved from the first quarter of this year when negative returns were experienced. The plan has experienced gains in both the second and third quarters resulting in positive returns on a year-to-date basis. However, consistent with other pension plans, our pension plan could be negatively impacted in 2009 as a result of the current economic uncertainty and financial market volatility. Should the plan incur negative returns in 2009, the deficit position at that time could lead to a large increase in our contribution requirements beyond 2009. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. As a result, the fund was negatively impacted in 2008 and into the first quarter of 2009 but has recovered in the second and third quarters of 2009, consistent with the returns experienced in financial markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In anticipation of this decision, we commenced our IFRS conversion project in 2007. The project was established with a formal project governance structure that includes a steering committee consisting of senior levels of management from finance, information technology, treasury and our operations organizations. Regular reporting is provided to our senior executive management and to the Audit and Finance Committee of our Board of Directors. We have also engaged an external expert advisor.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We have completed the diagnostic phase involving a high level review of the major differences between current Canadian Generally Accepted Accounting Principles (GAAP) and IFRS in all subject areas. In this phase, we determined that the areas of accounting difference with the highest potential to significantly impact our company are rate regulated accounting, accounting for fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

We have also completed the design and planning phase and are nearing completion of the solution development and implementation phases of our project. Issue-specific teams are focusing on documenting issues, generating options and making recommendations. Our teams are establishing key milestones, developing recommendations, analyzing financial system impacts, developing financial reports and carrying on ongoing discussions with our external auditors. We are evaluating the impacts of IFRS on all of our business activities, including our subsidiaries. We are also currently evaluating the impact of IFRS on our entity-wide information system.

The impacts of IFRS and potential solutions on disclosure controls and internal controls over financial reporting are also being examined. Analysis of other business impacts, such as impacts on debt covenants and performance measures, also continues. We have established a staff communication plan and have completed a significant number of staff training sessions, and additional future training planned.

In December 2008, the International Accounting Standards Board (IASB) added a project on rate regulated activities to its agenda and in July 2009, it issued an exposure draft providing its proposed accounting for Rate Regulated Activities. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. In addition, the exposure draft makes an exception to the requirements of other standards by allowing continued capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the costs' inclusion in rate base.

At a meeting held in November 2008, the Canadian Public Sector Accounting Board (PSAB) agreed to re-evaluate an earlier conclusion that government organizations following commercial practices, such as our company, continue to issue financial statements in accordance with GAAP for profit-oriented enterprises. For such enterprises that are also publicly accountable, this would become IFRS after January 1, 2011. On October 14, 2009, PSAB released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011.

On September 25, 2009, the Canadian Securities Administrators' staff reaffirmed their view that all registrants will be required to use IFRS commencing January 1, 2011, with the exception of members of self-regulating organizations.

In May 2008, the OEB began a process to determine the nature of any changes that should be made in regulatory reporting requirements in response to IFRS. The OEB held several consultation meetings and a formal stakeholder conference on this subject in May 2009. We participated fully in each of the OEB initiatives to date. On July 28, 2009, the OEB released its recommendations on how regulatory reporting requirements should change in response to IFRS. The OEB has initiated a second phase of the consultation to amend certain regulatory instruments. We are currently continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are continuing to transition our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

On August 5, 2009, we implemented Phase Two of an entity-wide systems improvement project which impacted processes within Finance, Human Resources, Payroll and Investment Management. The reporting tool Business Intelligence/Business Warehouse (BI/BW) was also implemented. This implementation included both new controls over Internal Controls over Financial Reporting and replaced controls in the previous information technology system. Our process documentation has been updated and certain controls have been tested for purposes of determining whether they have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

RECENT DEVELOPMENTS

Green Energy Act, 2009

On September 21, 2009 the Government of Ontario requested our company to proceed with planning and implementing 20 major transmission projects across Ontario in support of the Act, in anticipation of the increase in renewable energy generation associated with the Feed-in-Tariff program, which became effective on October 1, 2009, and the high demand for renewable generation connections. We have agreed with the Government's request and are proceeding with an implementation plan. These projects will also be part of our investment planning process.

Final Amendment to the Transmission System Code (TSC)

On October 20, 2009, the OEB issued final amendments to the TSC. The amendments promote the implementation of the Government's policy objectives by facilitating the timely and economically efficient connection of renewable generation facilities through the timely development of transmission "enabler" facilities that connect clusters of renewable projects to the grid. The amendments address issues associated with enabler facilities, including how the facilities are identified and providing for renewable generators to pay for their pro-rata share of the cost of those facilities up to the connection point.

Final Amendment to the Distribution System Code (DSC)

On October 21, 2009, the OEB issued final amendments to the DSC. The amendments promote the connection of renewable resources by retaining incentives to renewable generators to locate where their distribution connection costs are lower.

Bruce to Milton Transmission Reinforcement Project

On August 31, 2009, we filed a letter with the OEB to advise them of the potential for costs to materially exceed the OEB-approved amount of $635 million as a result of unanticipated delays in receiving both Environmental Assessment and Niagara Escarpment Commission approvals. Once the requisite approvals are received we will expect to provide an update to the OEB. We currently expect to spend in the range of $700 million.

Northwest Transmission Expansion Project

In October 2009, we initiated the planning for the Northwest Transmission Expansion project under Ontario's *Environmental Assessment Act*. If approved, the 430 kilometre, single circuit 230kV transmission line between Nipigon and Pickle Lake will improve reliability, increase transmission capacity and connect renewable generation to the grid.

Status of Rate Applications

Our subsidiary, Hydro One Networks, is currently preparing evidence to support our upcoming transmission rate application for the years 2011 and 2012. The application is anticipated to be filed with the OEB in early 2010.

On October 19, 2009, we submitted responses for interrogatories received from the OEB in relation to our 2010 and 2011 distribution rate application. An oral hearing is expected to commence on December 7, 2009.

Purchases and Sales of Electricity Utilities

On October 16, 2009, the Government of Ontario announced that it intends to make the exemption from the electricity transfer tax permanent for transfers of electricity assets within the public sector. This exemption provides publicly-owned electricity utilities with relief from paying the tax when they sell electricity assets to other publicly-owned electricity utilities in Ontario. We remain committed to a prudent and measured approach to distribution rationalization and we will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions) (except as otherwise noted)	**2009**	**2008**	**2009**	**2008**
Net income	100	112	359	367
Net cash from operating activities	274	364	653	848
Capital expenditures	400	321	1,119	835
Basic and fully diluted earnings per common share *(Canadian dollars)*	949	1,073	3,454	3,534
Earnings coverage ratio[1]			2.36	2.59
Net asset coverage on long-term debt[2]			1.80	1.84
Total debt to capitalization[3]			55%	54%

[1]The earnings coverage ratio has been presented for the twelve months ended September 30, 2009 and September 30, 2008, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at September 30, 2009 and December 31, 2008 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3]Total debt to capitalization ratio has been presented as at September 30, 2009 and December 31, 2008 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including amendments to codes, the impact of new regulatory guidelines and impacts of decisions from the OEB and other governing bodies; statements related to the status of our rate applications; statements regarding our future liquidity and capital resources; expectations regarding our financing activities; statements regarding our projects and completion dates; statements regarding future capital expenditures and our investment plans; statements relating to the *Green Energy Act, 2009*,

including the expected additional investments arising therefrom; statements regarding contractual obligations and other commercial commitments including planned courses of action; statements regarding future pension contributions and our pension plan; expectations regarding our strategy for acquisitions and divestitures of distribution assets; and statements about IFRS and our conversion to IFRS. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law. These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk that we are not able to arrange sufficient financing to repay maturing debt and to fund capital expenditures and other obligations;
- the impact of the *Green Energy Act, 2009* on our company, the additional investments arising therefrom and decisions regarding the recovery of the related capital expenditures;
- the risks associated with current economic uncertainty and financial market volatility; and
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2008 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at November 11, 2009. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Revenues				
Transmission	296	315	869	912
Distribution	831	797	2,620	2,454
Other	17	14	48	37
	1,144	1,126	3,537	3,403
Costs				
Purchased power	547	526	1,731	1,605
Operation, maintenance and administration *(Note 5)*	267	256	791	732
Depreciation and amortization	139	137	392	399
	953	919	2,914	2,736
Income before financing charges and provision for payments in lieu of corporate income taxes	191	207	623	667
Financing charges *(Note 5)*	79	73	225	217
Income before provision for payments in lieu of corporate income taxes	112	134	398	450
Provision for payments in lieu of corporate income taxes	12	22	39	83
Net income	100	112	359	367
Other comprehensive loss	-	-	-	(1)
Comprehensive income	100	112	359	366
Basic and fully diluted earnings per common share *(Canadian dollars)*	949	1,073	3,454	3,534

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Retained earnings, beginning of period	1,633	1,399	1,497	1,258
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	-	12	-
Net income	100	112	359	367
Dividends *(Note 3)*	(26)	(72)	(161)	(186)
Retained earnings, end of period	1,707	1,439	1,707	1,439

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Accumulated other comprehensive income, beginning of period	(10)	(10)	(10)	(9)
Other comprehensive loss	-	-	-	(1)
Accumulated other comprehensive income, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	September 30, 2009	December 31, 2008
Assets		
Current assets:		
Cash	-	16
Short-term investments	8	-
Accounts receivable (net of allowance for doubtful accounts)	768	754
Regulatory assets	60	64
Materials and supplies	22	19
Other *(Note 2)*	29	18
	887	871
Fixed assets:		
Fixed assets in service	18,006	17,334
Less: accumulated depreciation	(6,707)	(6,418)
	11,299	10,916
Construction in progress	1,238	912
Future use land, components and spares	135	132
	12,672	11,960
Long-term assets:		
Deferred pension asset	428	441
Regulatory assets *(Note 2)*	930	291
Goodwill	133	133
Intangible assets (net of accumulated amortization) *(Note 2)*	217	162
Future income tax assets *(Note 2)*	14	-
Other	14	18
	1,736	1,045
Total assets	15,295	13,876

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	September 30, 2009	December 31, 2008
Liabilities		
Current liabilities:		
Bank indebtedness	34	-
Accounts payable and accrued charges *(Note 2)*	694	791
Regulatory liabilities *(Note 2)*	95	43
Accrued interest	113	64
Short-term notes payable	60	-
Long-term debt payable within one year *(Note 4)*	400	400
	1,396	1,298
Long-term debt *(Note 4)*	6,232	5,733
Other long-term liabilities:		
Employee future benefits other than pension	940	908
Regulatory liabilities *(Note 2)*	512	564
Future income tax liabilities *(Note 2)*	626	-
Environmental liabilities	240	237
Long-term accounts payable and other liabilities	15	12
	2,333	1,721
Total liabilities	9,961	8,752
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings *(Note 2)*	1,707	1,497
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,334	5,124
Total liabilities and shareholder's equity	15,295	13,876

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Operating activities				
Net income	100	112	359	367
Environmental expenditures	(4)	(3)	(7)	(8)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	124	126	355	367
Revenue difference deferral account	-	(18)	-	(56)
Regulatory liability refund account	(7)	11	(17)	43
Other regulatory asset and liability accounts	2	(2)	(22)	1
Future income taxes	3	-	8	-
Amortization of debt costs	-	-	-	2
	218	226	676	716
Changes in non-cash balances related to operations	56	138	(23)	132
Net cash from operating activities	274	364	653	848
Financing activities				
Long-term debt issued	300	-	900	550
Long-term debt retired	-	-	(400)	(540)
Short-term notes payable	(165)	34	60	159
Dividends paid	(26)	(72)	(161)	(186)
Other	(4)	2	3	8
Net cash from (used in) financing activities	105	(36)	402	(9)
Investing activities				
Capital expenditures				
Fixed assets	(373)	(294)	(1,039)	(761)
Intangible assets	(27)	(27)	(80)	(74)
	(400)	(321)	(1,119)	(835)
Other assets	15	-	22	8
Net cash used in investing activities	(385)	(321)	(1,097)	(827)
Net change in cash and cash equivalents	(6)	7	(42)	12
Cash and cash equivalents, beginning of period *(Note 6)*	(20)	(7)	16	(12)
Cash and cash equivalents, end of period	(26)	-	(26)	-

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2008 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in Note 2.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Goodwill and Intangible Assets

Effective January 1, 2009, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3064, *Goodwill and Intangible Assets* which replaced CICA Handbook Sections 3062, *Goodwill and Other Intangible Assets*, and CICA Handbook Section 3450, *Research and Development Costs*. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

Upon adoption of the new accounting standard, on January 1, 2009, the Company reclassified $159 million in computer applications software previously classified as fixed assets to intangible assets. In addition, the Company also reclassified other assets with a net book value of $3 million that were previously classified as long-term other assets to intangible assets.

Change in Accounting Policy – Income Taxes

Effective January 1, 2009, the Company adopted amendments to the CICA Handbook Section 3465 - *Income Taxes* and CICA Handbook Section 1100 - *Generally Accepted Accounting Standards*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets. The temporary differences primarily relate to capital cost allowance in excess of deprecation and employee future benefits other than pension.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $20 million, long-term future income tax assets of $12 million and long-term future income tax liabilities of $503 million. The current future income tax assets are included with other assets on the Balance Sheet. The Company also recognized corresponding current regulatory liabilities of $29 million, long-term regulatory liabilities of $14 million and long-term regulatory assets of $526 million. An adjustment to retained earnings of $12 million was recorded as at January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate setting process.

3. DIVIDENDS

During the three months ended September 30, 2009, preferred dividends in the amount of $4 million (2008 - $4 million) and common dividends in the amount of $22 million (2008 - $68 million) were declared. During the nine months ended September 30, 2009, preferred dividends in the amount of $13 million (2008 - $13 million) and common dividends in the amount of $148 million (2008 - $173 million) were declared.

4. LONG-TERM DEBT

During the nine months ended September 30, 2009, Hydro One issued $900 million of additional notes under the Company's Medium-Term Note Program.

The first issue on January 13, 2009 was an additional offering of medium term notes with a principal amount of $100 million having a term of 1.8 years with a coupon rate of 3.89%. The notes are due on November 19, 2010. The original issue, on November 19, 2008 had a principal amount of $100 million, bringing the total amount outstanding for this issue to $200 million.

The second issue on January 14, 2009 was an additional offering of medium term notes with a principal amount of $200 million having a term of 4.8 years with a coupon rate of 5.0%. The notes are due on November 12, 2013. The original issue, on November 10, 2008 had a principal amount of $400 million, bringing the total amount outstanding for this issue to $600 million.

The third issue on March 3, 2009 was a medium term note with a principal amount of $300 million having a term of 30 years with a coupon rate of 6.03%. The notes are due on March 3, 2039.

The fourth issue on July 16, 2009 was a medium term note with a principal amount of $300 million having a term of 31 years with a coupon rate of 5.49%. The notes are due on July 16, 2040.

In the first quarter, the Company entered into three forward rate agreements in order to lock-in three interest rate resets on the floating rate it pays on a $250 million interest rate swap with settlement dates of March 3, 2009, June 3, 2009 and September 3, 2009 respectively. The three forward rate agreements were classified as held-for-trading and measured at fair value. The cash settlements on the forward rate agreements were not significant and were made on March 3, June 3, and September 3, 2009 respectively.

5. EMPLOYEE FUTURE BENEFITS

Pension Asset Transfer

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP, including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi LP. On March 10, 2008, the Company was granted consent from the Financial Services Commission of Ontario to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi LP Pension Plan. Under the agreement, the Company recognized a settlement of $21 million in its results of operations for the first quarter of 2008, inclusive of a related interest credit of $6 million. The pension asset transfer took place in the second quarter of 2008.

Total benefit costs are as follows:

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Pension				
Net periodic benefit cost	32	10	97	30
Pension fund contribution	28	25	84	75
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	10	33	29
Charged to results of operations	17	15	51	46

(Canadian dollars in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Employee Future Benefits Other than Pension				
Net periodic benefit cost	22	24	62	69
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	9	25	27
Charged to results of operations	13	15	37	42

6. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness."

7. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	296	831	17	1,144
Purchased power	-	547	-	547
Operation, maintenance and administration	109	144	14	267
Depreciation and amortization	62	75	2	139
Income before financing charges and provision for payments in lieu of corporate income taxes	125	65	1	191
Financing charges				79
Income before provision for payments in lieu of corporate income taxes				112
Capital expenditures	233	166	1	400
2008				
Segment profit				
Revenues	315	797	14	1,126
Purchased power	-	526	-	526
Operation, maintenance and administration	104	139	13	256
Depreciation and amortization	64	71	2	137
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	147	61	(1)	207
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				134
Capital expenditures	179	139	3	321

Nine months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	869	2,620	48	3,537
Purchased power	-	1,731	-	1,731
Operation, maintenance and administration	332	418	41	791
Depreciation and amortization	177	208	7	392
Income before financing charges and provision for payments in lieu of corporate income taxes	360	263	-	623
Financing charges				225
Income before provision for payments in lieu of corporate income taxes				398
Capital expenditures	638	477	4	1,119
2008				
Segment profit				
Revenues	912	2,454	37	3,403
Purchased power	-	1,605	-	1,605
Operation, maintenance and administration	306	392	34	732
Depreciation and amortization	185	209	5	399
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	421	248	(2)	667
Financing charges				217
Income before provision for payments in lieu of corporate income taxes				450
Capital expenditures	439	387	9	835

(Canadian dollars in millions)	September 30, 2009	December 31, 2008
Total assets		
Transmission	8,831	7,877
Distribution	6,344	5,873
Other	120	126
	15,295	13,876

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2009 unaudited interim Consolidated Financial Statements.